1

DEFINITIONS

1.1 INTRODUCTION

Hydraulic fracturing (also known as *hydrofracturing*, *hydrofracking*, *fracking*, *fraccing*, or *fracture stimulation technology*, or various other derivatives of the term) is a method by which access to crude oil and natural gas trapped in impermeable and hard-to-reach geologic formations is achieved.

The hydraulic fracturing process involves the pressurized injection of a fluid (fracturing fluid) into geologic formations (shale formations or unusually tight rock formations consisting of a clastic sedimentary rock composed of silt- to clay-sized grains) until the reservoir rock cracks (causing fractures in the formations) and then extending that fracture by continued injection of fluid. A solid proppant, typically sand, is also injected into the formation with the fracturing fluid so that the fracture cannot close and remains *propped open* by the proppant left behind. This creates a flow path for reservoir fluids to be rapidly produced from the reservoir. In terms of project timing, the process may take less than 1 month with reward being decadelong production of crude oil and natural gas. Thus, a general timeline might by on the order of:

Timeline (approximate, site specific):

Drilling (2–4 weeks)   Fracturing (3–5 days)   Producing oil/gas (decades)

Once the formation is fractured, the fluid pressure is reduced, which reverses the direction of fluid flow in the well toward the ground surface. Both the hydraulic fracturing fluid and any naturally occurring substances released from the underground formation are allowed to *flow back* to the ground surface. Thus, the term *flowback* is the portion of the injected fracturing fluid that flows back to the surface, along with oil, gas, and brine, when the well is produced.

In addition, hydraulic fracturing for enhancing crude oil and natural gas production can be categorized into three general subcategories according to process applied to the target formation to induce fracturing:

1. *Hydraulic fracturing* involves a relatively low rate of pressure loading that results in a bidirectional fracture extending outward from the well and oriented perpendicular to the least principal rock stress. Because of the creation of a single fracture and the ability to pump large volumes of fluids at (relatively) low rates, the potential penetration for the fracture into the formation can be extensive—on the order of hundreds of feet. This method is currently the most widely used in the coal-mine methane/coalbed methane (CMM/CBM) industry.

2. On the other hand, *explosive fracturing* involves rapid pressurization of the target formation, which results in a highly fractured zone around the wellbore, but usually not exceeding of approximately 10 ft. Because the peak pressures exceed both the minimum and maximum horizontal *in situ* stresses, a radial fracture pattern is created, which can exhibit advantageous fracture geometry where near-wellbore stimulation is the primary objective.

3. The third case involves *pulse fracturing* (Walter and Thompson, 1982), which is characterized by pressures exceeding both the maximum and minimum *in situ* stresses and which also creates a radial fracture pattern. This technique results in multiple vertical fractures extending radially from the wellbore, with penetrations on the order of 10–20 ft.

When used in combination with horizontal drilling (Chapter 5), hydraulic fracturing has allowed access to crude oil and natural gas reserves previously considered uneconomical because of the difficulty of access. The energy crises of the 1970s highlighted the importance of energy security, and governments took a more active role in encouraging domestic sources of supply, including unconventional sources of crude oil and natural gas (Speight, 2011). In addition, these reserves of crude oil and natural gas have the potential to assert a measure of energy independence that is necessary for countries that are experiencing a depletion of conventional crude oil and natural gas reserves and must rely upon imports of crude oil and natural gas from countries that, in many cases, do not have stable governments or stable energy policies (Speight, 2011, 2014a; Trembath et al., 2013).

On the US domestic scenario, hydraulic fracturing has been employed in the United States since 1947 but has only recently been used to produce large quantities of crude oil and natural gas from shale formations, as new technology for drilling horizontal wells has been deployed (Chapter 5) and, in spite of a variety of negative (often emotional rather than scientific) comments in various media, is projected to continue to play a central role in future domestic energy policy. Nevertheless, caution is advised because although hydraulic fracturing creates access to more crude oil and natural gas supplies, the process requires the use of large quantities of water and fracturing fluids, which are injected underground at high volumes and pressure. The

composition of the fracturing fluids varies by formation (therefore is site specific) and can range from a simple benign mixture of water and sand to more complex mixtures with a variety of chemical additives.

Despite the length of time that hydraulic fracturing has been used and despite the fact that the process has helped to create a benefit to energy production and economic growth (Chapter 5), there has been much negative attention that has given rise to serious concerns about the application of the technology. This is especially true in relation to the possibility (some would say *reality*) of contaminated drinking water because of the chemicals used in the process and the disturbance of the geological formations.

Because of the need for a thorough understanding of petroleum and natural gas and the associated technologies for recovery of these energy resources, it is essential that the definitions and the terminology of petroleum science and technology and associated resources (Table 1.1) be given prime consideration. This will aid in a better understanding of the variation in types of petroleum (with the exception of tar sand bitumen, which is not classed as petroleum), its constituents, the various fractions, and petroleum products. Of the many forms of terminology that have been used, not all have survived, but the more commonly used are illustrated here. Particularly troublesome, and more confusing, are those terms that are applied to the more viscous materials, for example, the use of the terms *tar sand bitumen* and *asphalt* (Speight, 2014a, 2015a, 2015c).

It is the purpose of this chapter to alleviate much of the confusion that exists, but it must be remembered that the terminology of petroleum and natural gas is still open to personal choice and historical usage. As always, but not always mentioned in this text, in favor of presenting the technical aspects of hydraulic fracturing, economics is also a major consideration.

1.2 DEFINITIONS

The types of liquids produced by fracturing and nonfracturing recovery processes from reservoirs and deposits vary substantially in character to the point where there can be considerable confusion when attempting to categorize the different liquids. It is valuable to place these liquids into various categories as defined by properties and/ or by recovery methods. Thus, the definitions by which the various liquids are known are a valuable asset in the petroleum and natural gas industries.

Definitions are the means by which scientists and engineers communicate the nature of a material to each other and to the world, through either the spoken or the written word. Furthermore, the definition of a material can be extremely important and have a profound influence on how the technical community and the public perceive that material.

The *definition* of petroleum and natural gas has been varied, unsystematic, diverse, and often archaic and is a product of many years of growth. Thus the long established use of an expression, however inadequate it may be, is altered with

TABLE 1.1   Simplified Differentiation between Conventional Crude Oil, Heavy Oil, Extra Heavy Oil, Tar Sand Bitumen, Oil Shale Kerogen, Tight Oil, and Coal

Conventional Crude Oil
  Mobile in the reservoir
  High-permeability reservoir
  Primary recovery
  Secondary recovery
Heavy Crude Oil
  Mobile in the reservoir
  High-permeability reservoir
  Secondary recovery
  Tertiary recovery (enhanced oil recovery (EOR), e.g., steam stimulation)
Extra Heavy Oil
  Mobile in the reservoir
  High-permeability reservoir
  Secondary recovery
  Tertiary recovery (enhanced oil recovery (EOR), e.g., steam stimulation)
Tar Sand Bitumen
  Immobile in the deposit
  High-permeability reservoir
  Mining (often preceded by explosive fracturing)
  Steam-assisted gravity drainage (SAGD)
Oil Shale Kerogen
  Immobile in the deposit
  Low-permeability reservoir
  May involve explosive fracturing
  In situ thermal decomposition to produce shale oil
  Mining followed by thermal decomposition to produce shale oil
Tight Oil
  Immobile in the reservoir
  Low-permeability reservoir
  Horizontal drilling into reservoir
  Fracturing (typically multifracturing) to release fluids/gases
Coalbed Methane
  Low- to medium-permeability reservoir (coal seam)
  Gas exists in pore spaces
  In situ thermal decomposition to produce liquid products
  Mining (often preceded by explosive fracturing), followed by thermal decomposition
  to produce liquid products

difficulty, and a new term, however precise, is at best adopted only slowly. Thus, because of the need for a thorough understanding of petroleum and the associated technologies, it is essential that the definitions and the terminology of petroleum and natural gas science and technology be given prime consideration here. Of the many forms of terminology that have been used, not all have survived, but the more common are illustrated here.

1.2.1 Petroleum

Petroleum (and the equivalent term *crude oil*) covers a wide assortment of naturally occurring liquids consisting of mixtures of hydrocarbons and other compounds containing variable amounts of sulfur, nitrogen, and oxygen, which may vary widely in volatility, specific gravity, and viscosity along with varying physical properties as illustrated in the variation in color from colorless to black (Fig. 1.1) (Speight, 2012a, 2014a; US EIA, 2014). Metal-containing constituents, notably those compounds consisting of derivatives of vanadium and nickel, usually occur in the more viscous crude oils in amounts up to several thousand parts per million and can have serious consequences for the equipment and catalysts used in processing of these feedstocks (Speight and Ozum, 2002; Parkash, 2003; Hsu and Robinson, 2006; Gary et al., 2007; Speight, 2014a).

Petroleum exists in reservoirs that consist of more porous and permeable sediments, such as *sandstone* and *siltstone*. A series of reservoirs within a common rock structure or a series of reservoirs in separate but neighboring formations is commonly referred to as an *oil field*. A group of fields is often found in a single geologic environment known as a *sedimentary basin* or *province*. In the underground locale, petroleum is much more fluid than it is on the surface and is generally mobile under reservoir conditions because the elevated temperatures (the *geothermal gradient*) in subterranean formations decrease the viscosity. Although the geothermal gradient varies from place to place, it is generally on the order of 25–30 °C/km (15 °F/1000 ft or 120 °C/1000 ft, i.e., 0.015 °C per foot of depth or 0.012 °C per foot of depth).
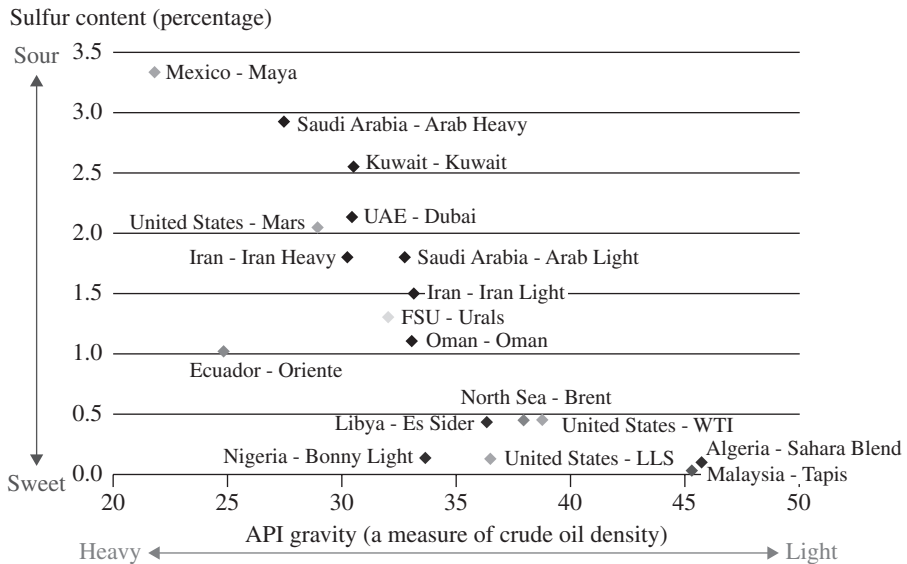

FIGURE 1.1 Properties of different crude oils. Source: US Energy Information Administration, US Department of Energy, Washington, DC (US EIA, 2014).

The major components of conventional petroleum are *hydrocarbons* and *nonhydrocarbons*, which display great variation in their molecular structure. The simplest hydrocarbons are a large group of chain-shaped molecules known as the *paraffins*. This broad series extends from methane, which forms natural gas, through liquids that are refined into gasoline to the highly crystalline wax. The *nonhydrocarbon constituents* of petroleum include organic derivatives of nitrogen, oxygen, sulfur, and the metals nickel and vanadium and are often referred to as polar aromatics, which include asphalt and resin constituents (Fig. 1.2). In the case of heavy oils and tar sand bitumen, there is a lesser amount of hydrocarbon constituents (volatile constituents) in favor of increasing amounts of nonhydrocarbon constituents (low-volatile and nonvolatile constituents) (Fig. 1.3). While most of these impurities are removed during refining by conversion of hydrocarbon products (Fig. 1.4), the low-volatile and nonvolatile constituents greatly influence the choice and effectiveness of recovery processes and whether or not fracturing is to be entertained as a recovery process enhancement (Chapter 3) (Speight, 2009, 2014a).

Geologic techniques can determine only the existence of rock formations that are favorable for petroleum occurrence, but drilling is the only sure way to ascertain the presence of petroleum in the formation. With modern rotary equipment, wells can be drilled to depths of more than 30,000 ft (9000 m). Once oil is found, it may be recovered (brought to the surface) by the pressure created by natural gas or water within the reservoir. Crude oil can also be brought to the surface by injecting water or steam into the reservoir to raise the pressure artificially or by injecting such substances as carbon dioxide, polymers, and solvents to reduce crude oil viscosity. Thermal recovery methods are frequently used to enhance the production of heavy crude oils, especially when extraction of the heavy oil is impeded by viscous resistance to flow at reservoir temperatures.
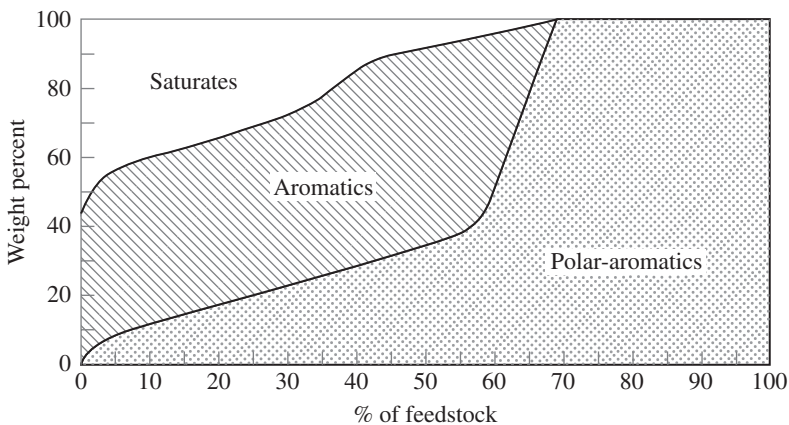

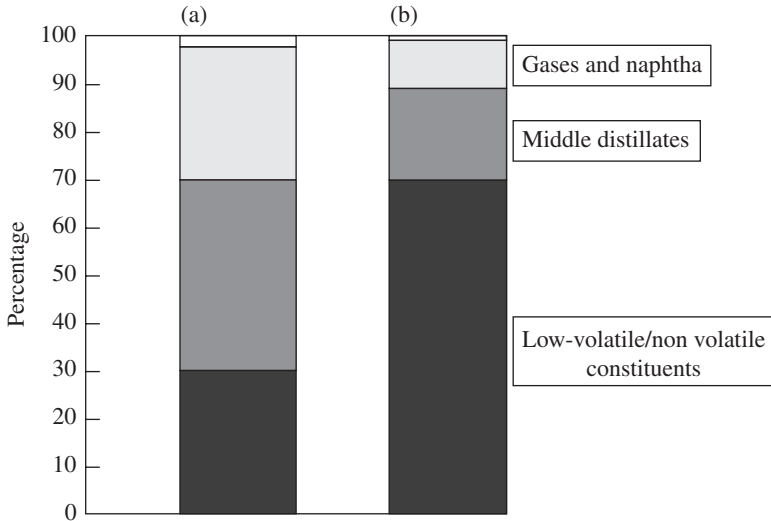**FIGURE 1.2** Schematic representation of petroleum composition.

FIGURE 1.3 Schematic comparison of the (a) composition of light crude oil with the (b) composition of heavy crude oil.
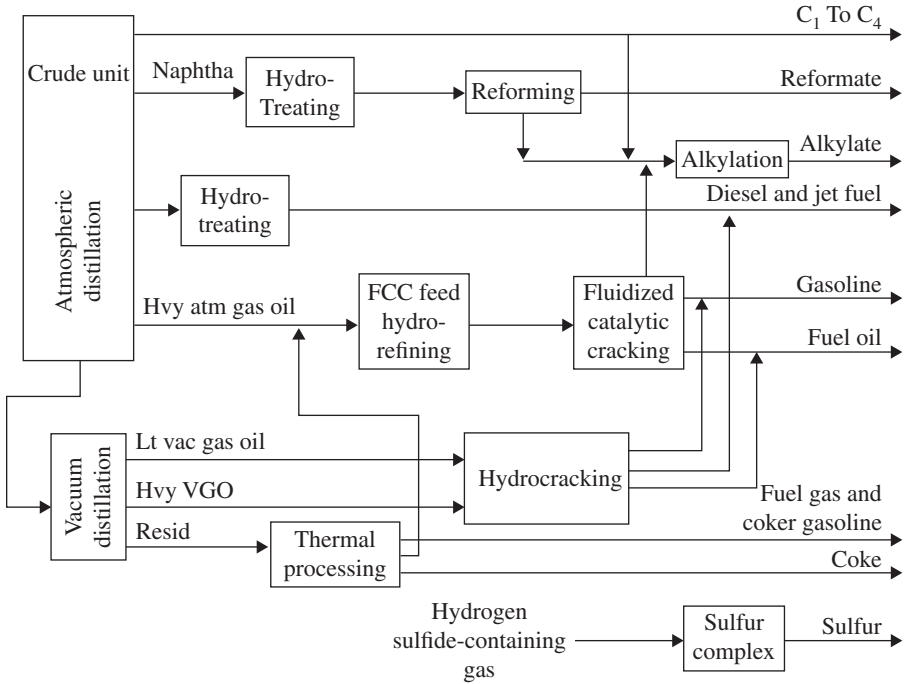

FIGURE 1.4 Schematic of a petroleum refinery.

1.2.2 Oil and Gas from Tight Formations

Tight formations scattered through North America have the potential to produce not only gas (*tight gas*) and crude oil (*tight oil*) (Fig. 1.5) (Law and Spencer, 1993; US EIA, 2011, 2013; Speight, 2013a). Such formations might be composted of shale sediments or sandstone sediments. In a conventional sandstone reservoir the pores are interconnected so gas and oil can flow easily from the rock to a wellbore. In tight sandstones, the pores are smaller and are poorly connected by very narrow capillaries, which results in low permeability. Tight gas and tight oil occur in sandstone sediments that have an effective permeability of less than 1 millidarcy (<1 mD).

FIGURE 1.5 Basins with the potential for tight oil production. Source: Energy Information Administration, US Department of Energy, Washington, DC.

One of the newest terms in the petroleum lexicon is the arbitrarily named (even erroneously named) *shale oil*, which is crude oil that is produced from tight shale formations and should not be confused with the older term *shale oil*, which is crude oil that is produced by the thermal treatment of oil shale and the ensuing decomposition of the kerogen contained within the shale (Scouten, 1990; Speight, 2012b). Oil shale represents one of the largest unconventional hydrocarbon deposits in the world with an estimated 8 trillion barrels (8×10^{12} bbl) of oil in place. Approximately 6 trillion barrels of oil in place is located in the United States including the richest and most concentrated deposits found in the Green River Formation in Colorado, Utah, and Wyoming. Documented efforts to develop oil shale to produce shale oil in the United States go back to approximate 1900, even earlier in Scotland (Scouten, 1990; Lee, 1991; Lee et al., 2007; Speight, 2008, 2012b). These prior efforts have produced a wealth of knowledge regarding the geological description as well as technical options and challenges for development. Thus far, however, none of these efforts have produced a commercially viable business in the United States. There need to be economically viable, socially acceptable, and environmentally responsible development solutions.

Recently, the introduction of the term *shale oil* to define crude oil from tight shale formations is the latest term to add confusion to the system of nomenclature of petroleum–heavy oil–bitumen materials. The term has been used without any consideration of the original term shale oil produced by the thermal decomposition of kerogen in oil shale (Scouten, 1990; Lee, 1991; Lee et al., 2007; Speight, 2008, 2012b). It is not quite analogous, but is certainly similarly confusing, to the term *black oil* that has been used to define petroleum by color rather than by any meaningful properties or recovery behavior (Speight, 2014a, 2015a).

Generally, unconventional tight oil and natural gas are found at considerable depths in sedimentary rock formations that are characterized by very low permeability. While some of the tight oil plays produce oil directly from shales, tight oil resources are also produced from low-permeability siltstone formations, sandstone formations, and carbonate formations that occur in close association with a shale source rock. It is important to note that in the context of this report, the term tight oil does not include resources that are commonly known as "oil shales," which refers to oil or kerogen-rich shale formations that are either heated *in situ* and produced or if surface accessible mined and heated (Scouten, 1990; Lee, 1991; Lee et al., 2007; Speight, 2008, 2012b).

The most notable tight oil plays in North America include the Bakken shale, the Niobrara Formation, the Barnett shale, the Eagle Ford shale, the Miocene Monterey play of California's San Joaquin Basin in the United States, and the Cardium play in Alberta. In many of these tight formations, the existence of large quantities of oil has been known for decades, and efforts to commercially produce those resources have occurred sporadically with typically disappointing results. However, starting in the mid-2000s, advancements in well drilling and stimulation technologies combined with high oil prices have turned tight oil resources into one of the most actively explored and produced targets in North America.

Of the tight oil plays, perhaps the best understood is the Bakken, which straddles the border between Canada and the United States in North Dakota, Montana, and

Saskatchewan. Much of what is known about the exploitation of tight oil resources comes from industry experiences in the Bakken, and the predictions of future tight oil resource development described in this study are largely based on that knowledge. The Bakken tight oil play historically includes three zones, or members, within the Bakken Formation. The upper and lower members of the Bakken are organic-rich shales that serve as oil source rocks, while the rocks of the middle member may be siltstone formations, sandstone formations, or carbonate formations that are also typically characterized by low permeability and high oil content. Since 2008 the Three Forks Formation, another tight oil-rich formation that directly underlies the lower Bakken shale, has also yielded highly productive oil wells. Drilling, completion, and stimulation strategies for wells in the Three Forks Formation are similar to those in the Bakken, and the light sweet crude oil that is produced from both plays has been geochemically determined to be essentially identical. Generally, the Three Forks Formation is considered to be part of the Bakken play, though the authors of published works will sometimes refer to it as the Bakken/Three Forks play.

Other known tight formations (on a worldwide basis) include the R'Mah Formation in Syria; the Sargelu Formation in the northern Persian Gulf region; the Athel Formation in Oman; the Bazhenov Formation and Achimov Formation in West Siberia, Russia; the Coober Pedy in Australia; the Chicontepec Formation in Mexico; and the Vaca Muerta field in Argentina (US EIA, 2011, 2013). However, tight oil formations are heterogeneous and vary widely over relatively short distances. Thus, even in a single horizontal drill hole, the amount of oil recovered may vary as may recovery within a field or even between adjacent wells. This makes evaluation of *shale plays* and decisions regarding the profitability of wells on a particular lease difficult, and tight reservoirs that contain only crude oil (without natural gas as the pressurizing agent) cannot be economically produced (US EIA, 2011, 2013).

By way of definition, a shale play is a defined geographic area containing an organic-rich fine-grained sedimentary rock that underwent physical and chemical compaction during diagenesis to produce the following characteristics: (i) clay- to silt-sized particles; (ii) high % of silica, and sometimes carbonate minerals; (iii) thermally mature; (iv) hydrocarbon-filled porosity, on the order of 6–14%; (5) low permeability, on the order of <0.1 mD; (6) large areal distribution; and (7) fracture stimulation required for economic production.

Success in extracting crude oil and natural gas from shale reservoirs depends largely on the hydraulic fracturing process (Chapter 5) that requires an understanding of the mechanical properties of the subject and confining formations. In hydraulic fracturing design, Young's modulus is a criterion used to determine the most appropriate fracturing fluid and other design considerations. Young's modulus provides an indication of the fracture conductivity that can be expected under the width and embedment considerations. Without adequate fracture conductivity, production from the hydraulic fracture will be minimal, or nonexistent (Akrad et al., 2011).

Typical of the crude oil from tight formations (*tight oil*, *tight light oil*, *and tight shale oil* have been suggested as alternate terms) is the Bakken crude oil, which is a light highly volatile crude oil. Briefly, Bakken crude oil is a light sweet (low-sulfur) crude oil that has a relatively high proportion of volatile constituents.

The production of the oil also yields a significant amount of volatile gases (including propane and butane) and low-boiling liquids (such as pentane and natural gasoline), which are often referred to collectively as (low-boiling or light) naphtha. By definition, natural gasoline (sometime also referred to as *gas condensate*) is a mixture of low-boiling liquid hydrocarbons isolate from petroleum and natural gas wells suitable for blending with light naphtha and/or refinery gasoline (Mokhatab et al., 2006; Speight, 2007, 2014a). Because of the presence of low-boiling hydrocarbons, low-boiling naphtha (*light naphtha*) can become extremely explosive, even at relatively low ambient temperatures. Some of these gases may be burned off (flared) at the field wellhead, but others remain in the liquid products extracted from the well (Speight, 2014a).

Bakken crude oil is considered to be a low-sulfur (*sweet*) crude oil, and there have been increasing observations of elevated levels of hydrogen sulfide (H_2S) in the oil. Hydrogen sulfide is a toxic, highly flammable, corrosive, explosive gas (hydrogen sulfide), and there have been increasing observations of elevated levels of hydrogen sulfide in Bakken oil. Thus, the liquids stream produced from the Bakken Formation will include the crude oil, the low-boiling liquids, and gases that were not flared, along with the materials and by-products of the hydraulic fracturing process. These products are then mechanically separated into three streams: (i) produced salt water, often referred to as brine, (ii) gases, and (iii) petroleum liquids, which include condensates, natural gas liquids, and light oil. Depending on the effectiveness and appropriate calibration of the separation equipment that is controlled by the oil producers, varying quantities of gases remain dissolved and/or mixed in the liquids, and the whole is then transported from the separation equipment to the well-pad storage tanks, where emissions of volatile hydrocarbons have been detected as emanating from the oil.

Oil from tight shale formation is characterized by low asphaltene content, low sulfur content, and a significant molecular weight distribution of the paraffinic wax content (Speight, 2014a, 2015a). Paraffin carbon chains of C_{10} to C_{60} have been found, with some shale oils containing carbon chains up to C_{72}. To control deposition and plugging in formations due to paraffins, the dispersants are commonly used. In upstream applications, these paraffin dispersants are applied as part of multifunctional additive packages where asphaltene stability and corrosion control are also addressed simultaneously (Speight, 2014a, 2014b, 2014c, 2015a, 2015b). In addition, scale deposits of calcite ($CaCO_3$), other carbonate minerals (minerals containing the carbonate ion, CO_3^{2-}), and silicate minerals (minerals classified on the basis of the structure of the silicate group, which contains different ratios of silicon and oxygen) must be controlled during production or plugging problems arise. A wide range of scale additives is available, which can be highly effective when selected appropriately. Depending on the nature of the well and the operational conditions, a specific chemistry is recommended, or blends of products are used to address scale deposition.

Another challenge encountered with oil from tight shale formations—many of which have been identified but undeveloped—is the general lack (until recently) of transportation infrastructure. Rapid distribution of the crude oil to the refineries is

necessary to maintain consistent refinery throughput—a necessary aspect of refinery design. Some pipelines are in use, and additional pipelines are being (and need to be) constructed to provide consistent supply of the oil to the refinery. During the interim, barges and railcars are being used, along with a significant expansion in trucking to bring the various crude oil to the refinery. For example, with development of suitable transportation infrastructure, production of Eagle Ford tight oil is estimated to increase by a substantial amount to approximately 2,000,000 bpd by 2017. Similar expansion in crude oil production is estimated for Bakken and other identified (and perhaps as yet unidentified and, if identified, undeveloped) tight formations.

While the basic approach toward developing a tight oil play is expected to be similar from area to area, the application of specific strategies, especially with respect to well completion and stimulation techniques, will almost certainly differ from play to play and often even within a given play. The differences depend on the geology (which can be very heterogeneous, even within a play) and reflect the evolution of technologies over time with increased experience and availability.

Finally, the properties of tight oil are highly variable. Density and other properties can show wide variation, even within the same field. The Bakken crude is light and sweet with an API of 42° and a sulfur content of 0.19% w/w. Similarly, Eagle Ford is a light sweet feed, with a sulfur content of approximately 0.1% w/w and with published API gravity between 40° API and 62° API.

In terms of refining, although tight oil is considered sweet (low sulfur content) and amenable to refinery options, this is not always the case. Hydrogen sulfide gas, which is flammable and poisonous, comes out of the ground with the crude oil and must be monitored at the drilling site as well as during transportation. Amine-based hydrogen sulfide scavengers are added to the crude oil prior to transport to refineries. However, mixing during transportation due to movement, along with a change in temperature that raises the vapor pressure of the oil, can cause the release of entrained hydrogen sulfide during offloading, thereby creating a safety hazard. For example, such crude that is loaded on railcars in winter and then transported to a warmer climate becomes hazardous due to the higher vapor pressure. The shippers and receivers of the oil should be aware of such risks.

Paraffin waxes are present in tight oil and remain on the walls of railcars, tank walls, and piping (Chapter 4). The waxes are also known to foul the preheat sections of crude heat exchangers (before they are removed in the crude desalter). Paraffin waxes that stick to piping and vessel walls can trap amines against the walls, which can create localized corrosion (Speight, 2014c). *Filterable solids* also contribute to fouling in the crude preheat exchangers, and a tight crude can contain over seven times more filterable solids than a traditional crude oil. To mitigate filter plugging, the filters at the entrance of the refinery require automated monitoring because they need to capture large volumes of solids. In addition, wetting agents are added to the desalter to help capture excess solids in the water, rather than allowing the undesired solids to travel further downstream into the process.

In many refineries, *blending two or more crude oils* as the refinery feedstock is now standard operating procedure that allows the refiner to achieve the right balance of feedstock qualities. However, the blending of the different crude oils may cause

problems if the crude oils being mixed are incompatible (Speight, 2014a). When crude oils are incompatible, increased deposition of the asphaltene constituents occurs (Chapter 4), which accelerates fouling in the heat exchanger train downstream of the crude desalter. Accelerated fouling increases the amount of energy that must be supplied by the crude fired heater, which limits throughput when the fired heater reaches its maximum duty and may also necessitate an earlier shutdown for cleaning.

Mixing stable crude oil blends with asphaltic and paraffinic oils creates the potential for precipitating the unstable asphaltenes—the high naphtha content of tight oils also creates favorable conditions for asphaltenes to more readily precipitate (Chapter 4) (Speight, 2014a, 2014c). It should be noted that the ratio of crude oils in a blend may have an impact on crude incompatibility. For example, a low amount of tight oil in a blend may not cause accelerated fouling, whereas a blend containing a higher amount of tight oil may cause fouling.

1.2.3 Opportunity Crudes

There is also the need for a refinery to be configured to accommodate *opportunity crude oils* and/or *high-acid crude oils*, which, for many purposes, are often included with heavy feedstocks (Speight, 2014a, 2014b; Yeung, 2014). *Opportunity crude oils* are either new crude oils with unknown or poorly understood properties relating to processing issues or are existing crude oils with well-known properties and processing concerns (Ohmes, 2014). Opportunity crude oils are often, but not always, heavy crude oils but in either case are more difficult to process due to high levels of solids (and other contaminants) produced with the oil, high levels of acidity, and high viscosity. These crude oils may also be incompatible with other oils in the refinery feedstock blend and cause excessive equipment fouling when processed either in a blend or separately (Speight, 2015b).

In addition to taking preventative measure for the refinery to process these feedstocks without serious deleterious effects on the equipment, refiners need to develop programs for detailed and immediate feedstock evaluation so that they can understand the qualities of a crude oil very quickly and it can be valued appropriately and management of the crude processing can be planned meticulously. For example, the compatibility of opportunity crudes with other opportunity crudes and with conventional crude oil and heavy oil is a very important property to consider when making decisions regarding which crude to purchase. Blending crudes that are incompatible can lead to extensive fouling and processing difficulties due to unstable asphaltene constituents (Speight, 2014a, 2015b). These problems can quickly reduce the benefits of purchasing the opportunity crude in the first place. For example, extensive fouling in the crude preheat train may occur, resulting in decreased energy efficiency, increased emissions of carbon dioxide, and increased frequency at which heat exchangers need to be cleaned. In a worst-case scenario, crude throughput may be reduced, leading to significant financial losses.

Opportunity crude oils, while offering initial pricing advantages, may have composition problems that can cause severe problems at the refinery, harming infrastructure, yield, and profitability. Before refining, there is the need for comprehensive

evaluations of opportunity crudes, giving the potential buyer and seller the needed data to make informed decisions regarding fair pricing and the suitability of a particular opportunity crude oil for a refinery. This will assist the refiner to manage the ever-changing crude oil quality input to a refinery—including quality and quantity requirements and situations, crude oil variations, contractual specifications, and risks associated with such opportunity crudes.

1.2.4 High-Acid Crude Oil

High-acid crude oils are crude oil that contains considerable proportions of naphthenic acids, which, as commonly used in the petroleum industry, refers collectively to all of the organic acids present in the crude oil (Shalaby, 2005; Rikka, 2007; Speight, 2014b). By the original definition, a naphthenic acid is a monobasic carboxyl group attached to a saturated cycloaliphatic structure. However, it has been a convention accepted in the oil industry that all organic acids in crude oil are called naphthenic acids. Naphthenic acids in crude oils are now known to be mixtures of low to high molecular weight acids, and the naphthenic acid fraction also contains other acidic species.

Naphthenic acids can be very water soluble to oil soluble depending on their molecular weight, process temperatures, salinity of waters, and fluid pressures. In the water phase, naphthenic acids can cause stable reverse emulsions (oil droplets in a continuous water phase). In the oil phase with residual water, these acids have the potential to react with a host of minerals, which are capable of neutralizing the acids. The main reaction product found in practice is the calcium naphthenate soap (the calcium salt of naphthenic acids). The total acid matrix is therefore complex, and it is unlikely that a simple titration, such as the traditional methods for measurement of the total acid number, can give meaningful results to be used in predictions of problems. An alternative way of defining the relative organic acid fraction of crude oils is therefore a real need in the oil industry, both upstream and downstream.

High-acid crude oils cause corrosion in the refinery—corrosion is predominant at temperatures in excess of 180 °C (355 °F) (Kane and Cayard, 2002; Ghoshal and Sainik, 2013) and occurs particularly in the atmospheric distillation unit (the first point of entry of the high-acid crude oil) and also in the vacuum distillation units. In addition, overhead corrosion is caused by the mineral salts, magnesium, calcium, and sodium chloride, which are hydrolyzed to produce volatile hydrochloric acid, causing a highly corrosive condition in the overhead exchangers. Therefore these salts present a significant contamination in opportunity crude oils. Other contaminants in opportunity crude oils that are shown to accelerate the hydrolysis reactions are inorganic clays and organic acids.

In addition to taking preventative measure for the refinery to process these feedstocks without serious deleterious effects on the equipment, refiners will need to develop programs for detailed and immediate feedstock evaluation so that they can understand the qualities of a crude oil very quickly and it can be valued appropriately and management of the crude processing can be planned meticulously.

1.2.5 Foamy Oil

Foamy oil is oil-continuous foam that contains dispersed gas bubbles produced at the wellhead from heavy oil reservoirs under solution gas drive. The nature of the gas dispersions in oil distinguishes foamy oil behavior from conventional heavy oil. The gas that comes out of solution in the reservoir does not coalesce into large gas bubbles nor into a continuous flowing gas phase. Instead it remains as small bubbles entrained in the crude oil, keeping the effective oil viscosity low while providing expansive energy that helps drive the oil toward the producing. Foamy oil accounts for unusually high production in heavy oil reservoirs under solution gas drive.

Thus, foamy oil is formed in solution gas drive reservoirs when gas is released from solution as reservoir pressure declines. It has been noted that the oil at the wellhead of these heavy oil reservoirs resembles the form of foam, hence the term *foamy oil*. The gas initially exists in the form of small bubbles within individual pores in the rock. As time passes and pressure continues to decline, the bubbles grow to fill the pores. With further declines in pressure, the bubbles created in different locations become large enough to coalesce into a continuous gas phase. Once the gas phase becomes continuous (i.e., when gas saturation exceeds the critical level)— the minimum saturation at which a continuous gas phase exists in porous media— traditional two-phase (oil and gas) flow with classical relative permeability occurs. As a result, the production gas–oil ratio (GOR) increases rapidly after the critical gas saturation has been exceeded.

1.2.6 Heavy Oil

When petroleum occurs in a reservoir that allows the crude material to be recovered by pumping operations as a free-flowing dark- to light-colored liquid, it is often referred to as *conventional petroleum*. Heavy oil is a *type* of petroleum that is different from the conventional petroleum insofar as they are much more difficult to recover from the subsurface reservoir. These materials have a much higher viscosity (and lower API gravity) than conventional petroleum, and primary recovery of these petroleum types usually requires thermal stimulation of the reservoir (Speight, 2009, 2014a). Heavy oil is more difficult to recover from the subsurface reservoir than light oils. The definition of heavy oils has been based on the API gravity or viscosity, and the definition is quite arbitrary although there have been attempts to rationalize the definition based upon viscosity, API gravity, and density.

For many years, petroleum and heavy oil were very generally defined in terms of physical properties. For example, heavy oils were considered to be those crude oils that had gravity somewhat less than 20° API with the heavy oils falling into the API gravity range 10–15°. For example, Cold Lake heavy crude oil has an API gravity equal to 12°, and extra heavy oils, such as tar sand bitumen, usually have an API gravity in the range 5–10° (Athabasca bitumen = 8° API). Residua would vary depending upon the temperature at which distillation was terminated, but usually vacuum residua are in the range 2–8° API (Speight, 2000; Speight and Ozum, 2002; Parkash, 2003; Hsu and Robinson, 2006; Gary et al., 2007).

Heavy oil has a much higher viscosity (and lower API gravity) than conventional petroleum, and recovery of these petroleum types usually requires thermal stimulation of the reservoir. The generic term *heavy oil* is often applied to a crude oil that has less than 20°API and usually, but not always, a sulfur content higher than 2% by weight (Speight, 2000). Furthermore, in contrast to conventional crude oils, heavy oils are darker in color and may even be black.

The term *heavy oil* has also been arbitrarily used to describe both the heavy oils that require thermal stimulation of recovery from the reservoir and the bitumen in bituminous sand (tar sand, *q.v.*) formations from which the heavy bituminous material is recovered by a mining operation.

1.2.7   Extra Heavy Oil

Briefly, extra heavy oil is a material that occurs in the solid or near-solid state and generally has mobility under reservoir conditions. However, *extra heavy oil* is a recently evolved term (related to viscosity) of little scientific meaning. While this type of oil may resemble tar sand bitumen and does not flow easily, extra heavy oil is generally recognized as having mobility in the reservoir compared to tar sand bitumen, which is typically incapable of mobility (free flow) under reservoir conditions. For example, the tar sand bitumen located in Alberta, Canada, is not mobile in the deposit and requires extreme methods of recovery to recover the bitumen. On the other hand, much of the extra heavy oil located in the Orinoco Belt of Venezuela requires recovery methods that are less extreme because of the mobility of the material in the reservoir.

Whether the mobility of extra heavy oil is due to a high reservoir temperature (that is higher than the pour point of the extra heavy oil) or due to other factors is variable and subject to localized conditions in the reservoir.

1.2.8   Tar Sand Bitumen

The term *bitumen* (also, on occasion, referred to as *native asphalt* and *extra heavy oil*) includes a wide variety of reddish-brown to black materials of semisolid, viscous to brittle character that can exist in nature with no mineral impurity or with mineral matter contents that exceed 50% by weight. Bitumen is frequently found filling pores and crevices of sandstone, limestone, or argillaceous sediments, in which case the organic and associated mineral matrix is known as *rock asphalt*.

Bitumen is a naturally occurring material that is found in deposits where the permeability is low and passage of fluids through the deposit can only be achieved by prior application of fracturing techniques. Tar sand bitumen is a high-boiling material with little, if any, material boiling below 350 °C (660 °F), and the boiling range approximates the boiling range of an atmospheric residuum.

Tar sands have been defined in the United States (FE-76-4) as

> *…the several rock types that contain an extremely viscous hydrocarbon which is not recoverable in its natural state by conventional oil well production methods including currently used enhanced recovery techniques. The hydrocarbon-bearing rocks are variously known as bitumen-rocks oil, impregnated rocks, oil sands, and rock asphalt.*

The recovery of the bitumen depends to a large degree on the composition and construction of the sands. Generally, the bitumen found in tar sand deposits is an extremely viscous material that is *immobile under reservoir conditions* and cannot be recovered through a well by the application of secondary or enhanced recovery techniques.

The expression *tar sand* is commonly used in the petroleum industry to describe sandstone reservoirs that are impregnated with a heavy, viscous black crude oil that cannot be retrieved through a well by conventional production techniques (FE-76-4, as mentioned previously). However, the term *tar sand* is actually a misnomer; more correctly, the name *tar* is usually applied to the heavy product remaining after the destructive distillation of coal or other organic matter (Speight, 1994). The bitumen in tar sand formations requires a high degree of thermal stimulation for recovery to the extent that some thermal decomposition may have to be induced. Current recovery operations of bitumen in tar sand formations that involve use of a mining technique and nonmining techniques are continually being developed (Speight, 2009, 2014a).

It is incorrect to refer to native bituminous materials as *tar* or *pitch*. Although the word tar is descriptive of the black, heavy bituminous material, it is best to avoid its use with respect to natural materials and to restrict the meaning to the volatile or near-volatile products produced in the destructive distillation of such organic substances as coal (Speight, 1994). In the simplest sense, pitch is the distillation residue of the various types of tar. Thus, alternative names, such as *bituminous sand* or *oil sand*, are gradually finding usage, with the former name (bituminous sands) more technically correct. The term *oil sand* is also used in the same way as the term *tar sand*, and these terms are used interchangeably throughout this text.

However, in order to define bitumen, heavy oil, and conventional petroleum, the use of a single physical parameter such as viscosity is not sufficient. Physical properties such as API gravity, elemental analysis, and composition fall short of giving an adequate definition. It is the properties of the bulk deposit and, most of all, the necessary recovery methods that form the basis of the definition of these materials. Only then is it possible to classify petroleum, heavy oil, and tar sand bitumen (Speight, 2009, 2014a).

1.2.9   Natural Gas

The generic term *natural gas* applies to gases commonly associated with petroliferous (petroleum-producing, petroleum-containing) geologic formations. Natural gas generally contains high proportions of methane (a single carbon hydrocarbon compound, CH_4), and some of the higher molecular weight paraffins (C_nH_{2n+2}) generally containing up to six carbon atoms may also be present in small quantities (Table 1.2). The hydrocarbon constituents of natural gas are combustible, but nonflammable nonhydrocarbon components such as carbon dioxide, nitrogen, and helium are often present in the minority and are regarded as contaminants.

TABLE 1.2   Constituents of Natural Gas

Name	Formula	Vol. %
Methane	CH_4	>85
Ethane	C_2H_6	3.8
Propane	C_3H_8	1–5
Butane	C_4H_{10}	1–2
Pentane[a]	C_5H_{12}	1–5
Carbon dioxide	CO_2	1–2
Hydrogen sulfide	H_2S	1–2
Nitrogen	N_2	1–5
Helium	He	<0.5

[a]Pentane and higher molecular weight hydrocarbons up to approximately C_{10}, including benzene, toluene, ethylbenzene, and xylenes.

In addition to the natural gas fund in petroleum reservoirs, there are also those reservoirs in which natural gas may be the sole occupant. The principal constituent of natural gas is methane, but other hydrocarbons, such as ethane, propane, and butane, may also be present. Carbon dioxide is also a common constituent of natural gas. Trace amounts of rare gases, such as helium, may also occur, and certain natural gas reservoirs are a source of these rare gases. Just as petroleum can vary in composition, so can natural gas. Differences in natural gas composition occur between different reservoirs, and two wells in the same field may also yield gaseous products that are different in composition (Speight, 1990, 2009, 2014a).

There are several general definitions that have been applied to natural gas. Thus, *lean* gas is gas in which methane is the major constituent. W*et* gas contains considerable amounts of the higher molecular weight hydrocarbons. S*our* gas contains hydrogen sulfide, whereas *sweet* gas contains very little, if any, hydrogen sulfide. *Residue gas* is natural gas from which the higher molecular weight hydrocarbons have been extracted, and *casing head gas* is derived from petroleum but is separated at the separation facility at the wellhead.

To further define the terms *dry* and *wet* in quantitative measures, the term *dry* natural gas indicates that there is less than 0.1 gallon (1 gallon, US, = 264.2 m³) of gasoline vapor (higher molecular weight paraffins) per 1000 ft³ (1 ft³ = 0.028 m³). The term *wet natural gas* indicates that there are such paraffins present in the gas, in fact more than 0.1 gal/1000 ft³.

Associated or *dissolved* natural gas occurs either as free gas or as gas in solution in the petroleum. Gas that occurs as a solution in the petroleum is *dissolved* gas, whereas the gas that exists in contact with the petroleum (*gas cap*) is *associated* gas.

Other components such as carbon dioxide (CO_2), hydrogen sulfide (H_2S), mercaptans (thiols; RSH), as well as trace amounts of other constituents may also be present. Thus, there is no single composition of components that might be termed *typical* natural gas. Methane and ethane constitute the bulk of the combustible components; carbon dioxide (CO_2) and nitrogen (N_2) are the major noncombustible (inert) components.

Thus, sour gas is natural gas that occurs mixed with higher levels of sulfur, creating hydrogen sulfide (H_2S), a corrosive gas. This sour gas requires additional processing for purification (Mokhatab et al., 2006; Speight, 2007).

Natural gas condensate (*gas condensate*, *natural gasoline*) is a low-density, low-viscosity mixture of hydrocarbon liquids that are present as gaseous components in the raw natural gas produced from natural wells. The constituents of *condensate* separate from the untreated (raw) gas if the temperature is reduced to below the hydrocarbon dew-point temperature of the raw gas. Briefly, the dew point is the temperature to which a given volume of gas must be cooled, at constant barometric pressure, for vapor to condense into liquid. Thus, the dew point is the saturation point.

There are many condensate sources worldwide and each has its own unique gas-condensate composition. However, in general, gas condensate has a specific gravity on the order of ranging from 0.5 to 0.8 and is composed of hydrocarbons such as propane, butane, pentane, hexane, heptane and even octane, nonane, and decane in some cases. In addition, condensate may contain additional impurities such as hydrogen sulfide, thiols (RSH, also called mercaptans), carbon dioxide, cyclohexane, and low molecular weight aromatics such as benzene, toluene, ethylbenzene, and xylenes (Mokhatab et al., 2006; Speight, 2007, 2014a).

When condensation occurs in the reservoir, the phenomenon known as condensate blockage can halt flow to the wellbore. Hydraulic fracturing is the most common mitigating technology in siliciclastic reservoirs (reservoirs composed of clastic rocks), and acidizing is used in carbonate reservoirs. Both techniques increase the effective contact area with a formation. Production can be improved with less drawdown in the formation. For some gas-condensate fields, a lower draw-down means single-phase production above the dew-point pressure can be extended for a longer time. However, hydraulic fracturing does not generate a permanent conduit past a condensate saturation buildup area. Once the pressure drops below the dew point, saturation will increase around the fracture, just as it did around the wellbore. Horizontal or inclined wells are also being used to increase contact area within formations.

1.2.10   Shale Gas

Shale gas (also called *tight gas*) is a description for a field in which natural gas accumulation is locked in tiny bubble-like pockets within layered low-permeability sedimentary rock such as shale. The terms *shale gas* and *tight gas* are often used interchangeably, but there are differences—while shale gas is trapped in rock, tight gas describes natural gas that is dispersed within low-porosity silt or sand areas that create a tight-fitting environment for the gas. Typically, tight gas refers to natural gas that has migrated into a reservoir rock with high porosity but low permeability. These types of reservoirs are not usually associated with oil and commonly require horizontal drilling and hydraulic fracturing to increase well output to cost-effective levels. In general, the same drilling and completion technology that is effective with shale gas can also be used to access and extract tight gas. Shell uses proven technology in responsible ways to access this needed resource.
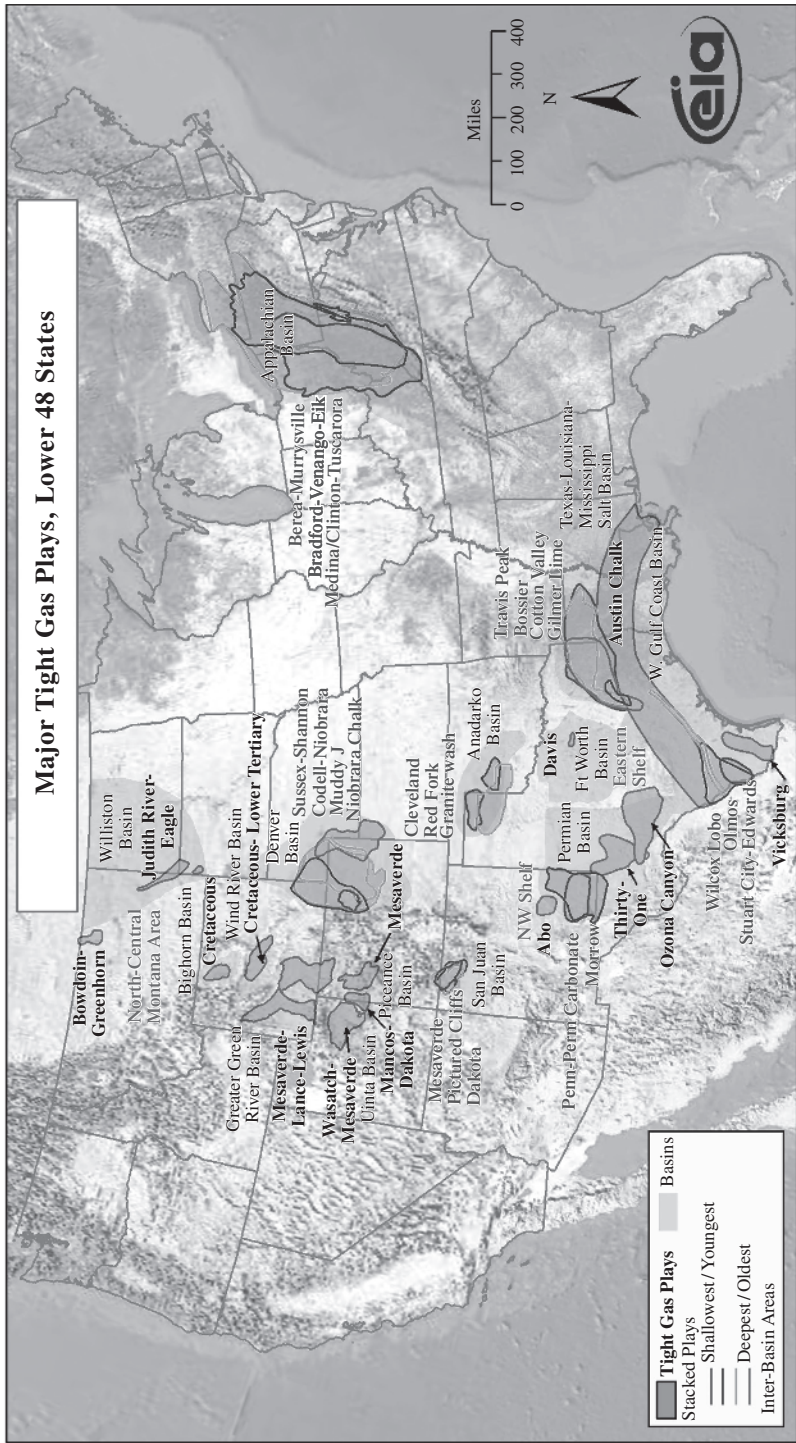
FIGURE 1.6   Tight Gas Plays of the United States. Source: Energy Information Administration, US Department of Energy, Washington, DC.

Tight gas is the fastest-growing natural gas resource in the United States and worldwide as a result of several recent developments (Fig. 1.6). Advances in horizontal drilling technology allow a single well to pass through larger volumes of a shale gas reservoir and thus produce more gas. The development of hydraulic fracturing technology has also improved access to shale gas deposits. This process requires injecting large volumes of water mixed with sand and fluid chemicals into the well at high pressure to fracture the rock, increasing permeability and production rates.

To extract tight gas, a production well is drilled vertically until it reaches the shale formation, at which point the wellbore turns to follow the shale horizontally. As drilling proceeds, the portion of the well within the shale is lined with steel tubing (casing). After drilling is completed, small explosive charges are detonated to create holes in the casing at intervals where hydraulic fracturing is to occur. In a hydraulic fracturing operation, the fracturing fluid is pumped in at a carefully controlled pressure to fracture the rock out to several hundred feet from the well. Sand mixed with the fracturing fluid acts to prop these cracks open when the fluids are subsequently pumped out. After fracturing, gas will flow into the wellbore and up to the surface, where it is collected for processing and sales.

1.2.11   Coalbed Methane (CBM)

Natural gas is often located in the same reservoir as with petroleum, but it can also be found trapped in gas reservoirs and within coal deposits. The occurrence of methane in coal seams is not a new discovery, and methane (called *firedamp* by the miners because of its explosive nature) was known to coal miners for at least 150 years (or more) before it was *rediscovered* and developed as CBM (Speight, 2013b).

The natural gas can originate by thermogenic alteration of coal or by biogenic action of indigenous microbes on the coal. There are some horizontally drilled CBM wells and some that receive hydraulic fracturing treatments. However, some CBM reservoirs are also underground sources of drinking water, and as such, there are restrictions on hydraulic fracturing operations. The CBM wells are mostly shallow, as the coal matrix does not have the strength to maintain porosity under the pressure of significant overburden thickness.

In coalbeds (coal seams), methane (the primary component of natural gas) is generally adsorbed to the coal rather than contained in the pore space or structurally trapped in the formation. Pumping the injected and native water out of the coalbeds after fracturing serves to depressurize the coal, thereby allowing the methane to desorb and flow into the well and to the surface. Methane has traditionally posed a hazard to underground coal miners, as the highly flammable gas is released during mining activities. Otherwise inaccessible coal seams can also be tapped to collect this gas, known as CBM, by employing similar well drilling and hydraulic fracturing techniques as are used in shale gas extraction.

CBM is a gas formed as part of the geological process of coal generation and is contained in varying quantities within all coal. CBM is exceptionally pure compared to conventional natural gas, containing only very small proportions of higher molecular weight hydrocarbons such as ethane and butane and other gases (such as

hydrogen sulfide and carbon dioxide). Coalbed gas is over 90% methane and, subject to gas composition, may be suitable for introduction into a commercial pipeline with little or no treatment (Levine, 1993; Rice, 1993; Mokhatab et al., 2006; Speight, 2007, 2013a). Methane within coalbeds is not structurally trapped by overlying geologic strata, as in the geologic environments typical of conventional gas deposits (Speight, 2007, 2013a, 2014a). Only a small amount (on the order of 5–10% v/v) of the CBM is present as free gas within the joints and cleats of coalbeds. Most of the CBM is contained within the coal itself (adsorbed to the sides of the small pores in the coal).

The primary (or natural) permeability of coal is very low, typically ranging from 0.1 to 30 mD, and because coal is a very weak (low modulus) material and cannot take much stress without fracturing, coal is almost always highly fractured and cleated. The resulting network of fractures commonly gives coalbeds a high secondary permeability (despite coal's typically low primary permeability). Groundwater, hydraulic fracturing fluids, and methane gas can more easily flow through the network of fractures. Because hydraulic fracturing generally enlarges preexisting fractures in addition to creating new fractures, this network of natural fractures is very important to the extraction of methane from the coal.

1.2.12 Other Sources of Gas

Methane hydrates, which consist of methane molecules trapped in a cage of water molecules, occur as crystalline solids in sediments in Arctic regions and below the floor of the deep ocean. Although taking on the appearance of ice, methane hydrates will burn if ignited. Methane hydrates are the most abundant unconventional natural gas source and the most difficult to extract. Methane hydrates are conservatively estimated to hold twice the amount of energy found in all conventional fossil fuels, but the technical challenges of economically retrieving the resource are significant. There is also a significant risk that rising temperatures from global warming could destabilize the deposits, releasing the methane—a potent greenhouse gas—into the atmosphere and further exacerbating the problem.

Biogenic gas (predominantly methane) is produced by certain types of bacteria (methanogens) during the process of breaking down organic matter in an oxygen-free environment. Livestock manure, food waste, and sewage are all potential sources of biogenic gas, or biogas, which is usually considered a form of renewable energy. Small-scale biogas production is a well-established technology in parts of the developing world, particularly Asia, where farmers collect animal manure in vats and capture the methane given off while it decays.

Landfills offer another underutilized source of biogas. When municipal waste is buried in a landfill, bacteria break down the organic material contained in garbage such as newspapers, cardboard, and food waste, producing gases such as carbon dioxide and methane. Rather than allowing these gases to go into the atmosphere, where they contribute to global warming, landfill gas facilities can capture them, separate the methane, and combust it to generate electricity, heat, or both.

1.3 UNCONVENTIONAL OIL

Unconventional oil is an all-encompassing definition that can also include several of the crude oil, heavy oil, and tar sand bitumen toys defined earlier. For general purposes, the term *unconventional oil* is synonymous with crude oil, heavy oil, extra heavy oil, and tar sand bitumen that cannot be produced, transported, or refined using traditional techniques of which oil produced by hydraulic fracturing of shale formations and tight formations is also included. But caution is advised at this point since fracturing techniques have been in used since the 1940s to recover residual crude oil from depleted and difficult-to-produce formations.

In the more recent sense of the use of the term, unconventional heavy oil occurs throughout the world—the largest resources are the extra-heavy-oil-bearing deposits in Venezuela and the tar sand deposits of Athabasca (northeastern Alberta, Canada). The United States also has oil sand deposits. However, not all unconventional oils are heavy, and a growing source of unconventional supply is tight oil, which is produced from low-permeability siltstone formations, sandstone formations, and carbonate formations. The crude oil produced from such formations has the same properties (such as API gravity, viscosity, and sulfur content) as conventional oil.

Historically, the crude oil in tight formations was locked in the formations and could not flow through the tight formation rock. However, recent advancements in horizontal drilling and well fracturing technologies are now enabling production of the tight oil—notable plays include the Bakken play (which underlies parts of North Dakota, Montana, Saskatchewan, and Manitoba), the Eagle Ford play in Texas, the Cardium play in Alberta, and the Miocene Monterey play in California. The Bakken is the largest tight oil play and produces a highly volatile light sweet crude oil. Unconventional oil is also produced from oil shale deposits, but this oil does not occur naturally and is produced by the thermal decomposition of kerogen—the organic compound of oil shale. Unlike conventional oil and gas operations, the kerogen is heated *in situ* or mined (as a component of the mined rock) and thermally into a crude oil-like product (*shale oil*) (Scouten, 1990; Lee, 1991; Lee et al., 2007; Speight, 2008, 2012b).

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